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Completion Design Optimization for Production Wells on Badra Oilfield

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Abstract

Badra oilfield started production in 2014.

After some time from the beginning of the field operation, several troubles manifested itself.

Analysis of tubing performance detected clear indication of gas slippage effect on low rate wells and tubing choking effect on high rate wells. Several issues with well integrity also lead to re-assessment of completion design.

During selection of new tubing size and completion equipment, factors like production rate, reservoir depletion, GOR, Flowing buttonhole pressure, wellhead pressure and temperature were taken into account.

In addition to that, possible well interventions and expected tubing loads were considered.

As a result three groups of wells have been identified - low, high and medium production rates in terms of Badra field with new completion concept for each group.

New completion design was selected and implemented on several wells and showed its better performance for new production conditions.

Moreover, selected production tubing diameter and completion components has lower cost and allows any well interventions that might be planned on the field. In addition to that, new completion string can last longer due to its higher corrosion allowance.

Introduction

Badra oilfield sarted production in 2014.

By the time of the first wells been drilled there was not too many experience obtained about the field geology and production issues.

Well by well there was a good improvement in drilling timing, but not too much clearance about drainage zones performance. Faulty nature of the field made it even more difficult.

Initially predicted production rate was 1080 m3/day (6700 bbl/d) and completion concept was designed for that rate.

Several issues manifested itself after a number of wells have been drilled and completed.

The most important issues were interruption of production and rising of A-annulus pressure.

Well performance analysis showed the reasons for tubing design re-assessment.

Following results of corrosion logs shown presence of corrosion that was a basis for material selection re-assessment.

Current paper shows how completion design was changed and what results were achieved based on short experience of field development.

Oilfield brief description

Badra Oilfield is located in central part of Iraq, Wasit province.

Current reservoir development strategy is Depletion drive.

- Average production zone depth is 4350 m TVD (14270 ft)
- Gross Formation thickness - 370 m (1214 ft)
- Oil Net pay thickness - 78 m (256 ft)
- Rock type – Fractured and porous limestones
- Laminated structure of formation
- Porosity 0.1 frac.
- Permeability of 1-30 mD;
- Concentration of H_2S 3-6 mole % and CO_2 3-6 mole %;
- Initial reservoir pressure was 509 bar (7380 psi)
- Average reservoir temperature is 122 °C for all existing wells

PVT properties:

- Oil density – 847 kg/m3
- Oil Viscosity – 10.18 cP at standard conditions
- Bubble point pressure: 270 bar (3915 psi)
- Solution GOR: 250 m3/m3 (1400 scf/bbl)

Problem identification

After several years since Badra oilfield has been put on production and sufficient amount of information has been accumulated, some troubles have manifested itself.

One of the problems is relatively quick production rate decline and following production interruption on some wells that have recently been drilled.

These well's behaviour looks different comparing to other wells, that have been drilled several years earlier and still keeping stable production on appropriate level.

Flow interruptions were accompanied by rapid reduction of wellhead temperature, impossibility of taking samples and zero production rate on flow meter. It was clearly defined that well switches over to gas.

During some time after troubles have started it was still possible to bring wells back to normal production by reducing the choke size. However later on as reservoir pressure was depleted, it was necessary to shut the wells for several days for pressure build up.

Finally, the maximum choke size for low production wells where problems observed is 28-30%.

Further choke opening directly leads to flow interruption and switch over to gas, whereas reducing the choke size down to 15-20% moves the well to unstable region and flow stops.

All wells fluids have similar PVT properties because only one formation is in development. Gross production intervals depths 4300-4700 m (14107-15420 ft) TVD, and Net perforation intervals 80 m (262 ft). Gross reduction intervals and net perforation intervals are similar on every well.

Initial predictions of production rate was estimated as 1080 m3/day (6800 bbl/d).

But mostly because of faulty structure of the field production rate variation is 200-1900 m3/day (1260-11950 bbl/d). No water breakthrough were observed by the time (apart of one well where water bearing zone was perforated for OWC confirmation).

Moreover, there are no any similar Oilfields in the region that have similar geological structure, well depths and production history. That makes field development strategy and rate prediction more complicated.

Most of the Oil production is located in South part of Iraq. Typical Iraqi production well has depth of 3000-3500 m (9843 - 11483) TVD, production rate around 480-790 m3/d (3000-5000 bbl/d).

All Badra production wells drilled to almost similar depth, thus significant wellhead temperature variation caused by difference in rates.

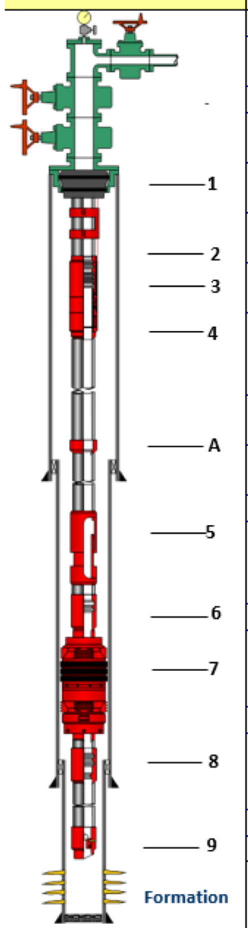
Low production wells mostly have WHT around 50 °C, whereas high production wells around 80 C. Production disruption occurred only on low production wells with WHT around 50 °C.

Thus the main task was to determine the optimum production tubing size for low production wells and wells after workover.

Initial completion design

Initial completion designed for wells with expected production rate of 1080 m3/d (6800 bbl/d). (Pic 1)

LAYOUT



No	Part No	S/N	DESCRIPTION	I.D.	O.D.
			ELEVATION		
1			5-1/2" 23# TSH Wedge 563 BxB	4,830	10,920
			Cross Over 5-1/2" TSH Wedge 563 Pin x 5-1/2" VamTop Pin	4,670	5,550
	8		5-1/2" Tubing, 23 ppf VamTop Box x Pin, L80	4,670	5,960
			Pup Joint 5-1/2" 23 ppf VamTop Box x Pin, L-80	4,670	5,960
2			Flow Coupling, 6ft, 5-1/2" 23 ppf VamTop BxP, Alloy 925	4,600	6,200
3			TRSV, SP, H2S, 7.5K, 5 1/2" 23# VamTop Box x Pin, Alloy-925	4,437	7,990
4			Flow Coupling, 6ft, 5-1/2" 23 ppf VamTop BxP, Alloy 925	4,600	6,200
			Pup Joint 5-1/2" 23 ppf VamTop Box x Pin, L-80	4,670	5,960
	357		5-1/2" Tubing, 23 ppf VamTop Box x Pin, L80	4,670	5,960
A			Crossover 5-1/2" VamTop Box x 3-1/2" VamTop Pin	2,992	6,156
	62		3-1/2" Tubing, 9.2 ppf VamTop Box x Pin, L80	2,992	3,900
			Pup Joint 3-1/2" 9.2 ppf VamTop Box x Pin, L-80	2,992	3,900
5			Travel Joint 4 SHEAR PINNED, 10 ft Stroke, 3-1/2" 9.2# VamTop BxP, Alloy-925	2,880	5,030
			Pup Joint 3-1/2" 9.2 ppf VamTop Box x Pin, L-80	2,992	3,900
	1		3-1/2" Tubing, 9.2 ppf VamTop Box x Pin, L80	2,992	3,900
			Pup Joint 3-1/2" 9.2 ppf VamTop Box x Pin, L-80	2,992	3,900
6			Nipple, 2,813" X Landing Profile, 3-1/2" VamTop BxP, Alloy-	2,813	4,550
			Pup Joint 3-1/2" 9.2 ppf VamTop Box x Pin, L-80	2,992	3,900
7			Hydraulic-set retrievable Packer, 7 " 23-29# Casing, 3-1/2" 9.2# VamTop BxP	2,885	5,980
			Pup Joint 3-1/2" 9.2 ppf VamTop Box x Pin, L-80	2,992	3,900
	1		3-1/2" Tubing, 9.2 ppf VamTop Box x Pin, L80	2,992	3,900
			Pup Joint 3-1/2" 9.2 ppf VamTop Box x Pin, L-80	2,992	3,900
8			XN, 2.750" XN No-Go Landing Nipple, 3 1/2" 9.2# VamTop Bxp 2.635" No-Go ID, Alloy-925	2,635	4,300
			Pup Joint 3-1/2" 9.2 ppf VamTop Box x Pin, L-80	2,992	3,900
			Crossover 3 1/2" 9.2 ppf VamTop Box x 3 1/2" 12.95 ppf TSH PH6 Pin	2,940	3,935
	13		3-1/2" Tubing, 12.95 ppf L80 TPS-Multiseal-TS-6 SMLS R2	2,750	3,935
			Crossover 3 1/2" 12.95 ppf TSH PH6 Box x 3 1/2" 9.2 ppf VamTop Pin	2,687	4,313
9			WLEG W/ Pump-out ball seat , 3 1/2" 9.2" ppf VamTop Box	2,949	4,270
			END OF TUBING		

Picture 1—Initial completion design

Generally speaking, completion is presented by 5 ½" × 3 ½" production tubing string, 3 ½" travel joint and 3 ½" MFA production packer (pull to release).

Original tubing stress analysis has shown sufficient resistance to expected loads (in case if travel joint is installed). No information about corrosion allowance has been provided by that time due to no accumulated corrosion logging statistics.

Actions taken

The first step was performing the Nodal Analysis to understand current situation on the field. Models were matched to latest well test parameters (flowing bottomhole pressure, wellhead pressure, production rate, GOR and reservoir pressure).

Nodal Analysis outcomes were used in conjunction with wells production parameters for proper understanding of wells performance and possible problems identification.

The main target was to analyse wells that produce in stable/unstable modes and Optimal/Not Optimal modes.

For Badra conditions:

Stable mode – there is no flow interruptions and switches over to gas.

Optimal mode - For new wells the optimum mode is characterised by choke opened for100% and FBHP is equal or more than target. It is normal when FBHP is higher than target for some time after production has started. Following reservoir pressure depletion will cause flow reduction and increasing the Total GOR. Thus beaning back the choke will keep the well on stable production until the well is reached the minimum stable flow (depends on tubing size selected).

Obtained results

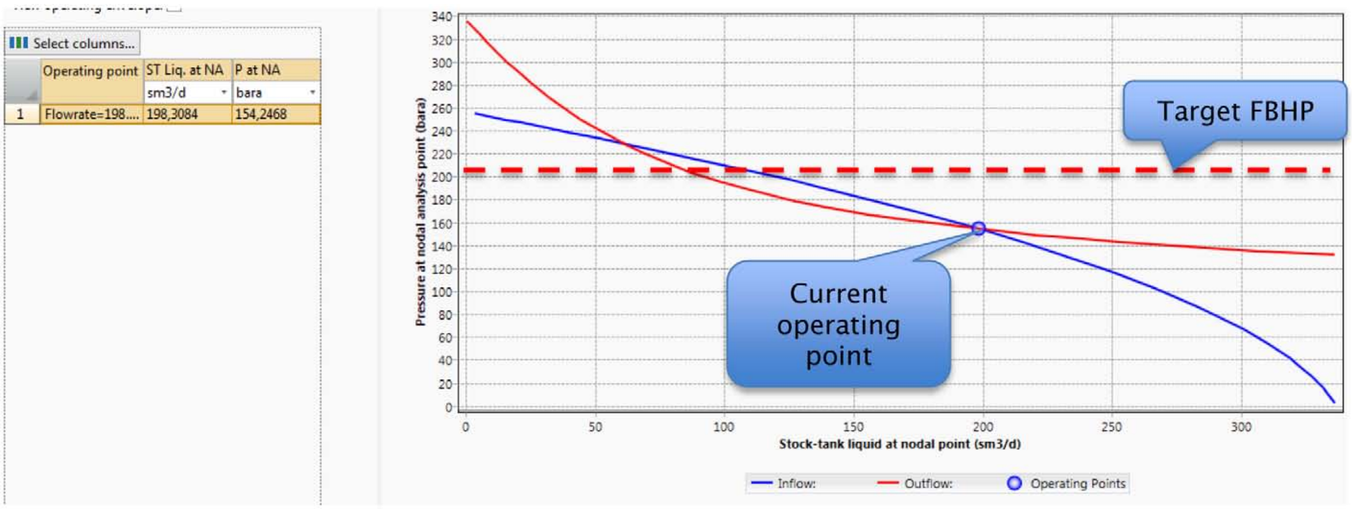
Results of wells performance analysis have identified three categories of wells and two main problems.

1. Low production wells with gas slippage and liquid hold up effect.

Low production wells for Barda field conditions are wells that produce less than 300 m3/d. (1890 bbl/d) Typical characteristics of flow interruptions on that wells are:

- Rapid temperature decline
- Increase of WHP
- Impossibility to take a sample from the flowline
- Downwarding VLP curve

Typical example of production well that works in unstable and non-optimal mode is presented below. (Pic 2)

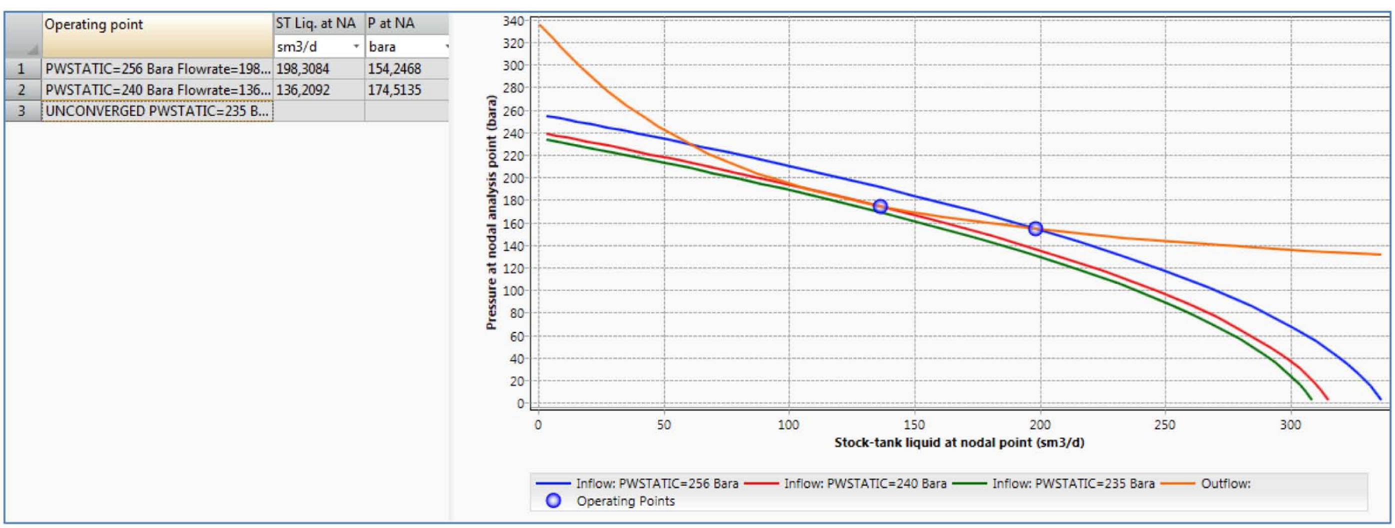


Picture 2—Unstable flow regime of the well

The main production tubing string of that well is presented by 5 ½" tubing. Once the flow rate reduces to 250 m3/d (1570 bbl/d) the well starts fluctuating and switches over to gas.

All of this happens with choke size around 25-30%. At the same time FBHP is lower than target BHP (200 bar, 2900 psi). Following choke reduction does not make the flow better. This kind of wells are now operated in periodical mode.

Minimum Pres at which the well is still capable to flow is 240 bar (3480 psi). However, it does not mean that flow would be stable. Well turns into unstable mode at 250 m3/day (1570 bbl/d). (Pic 3)



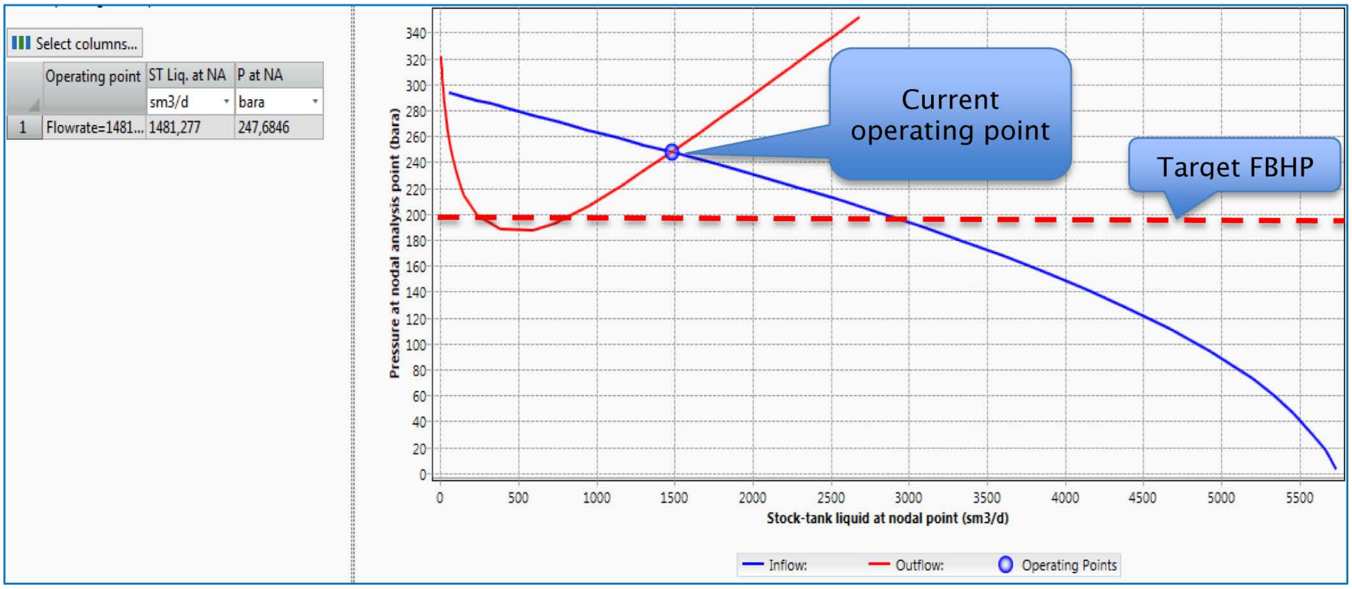
Picture 3—Well inflow/outflow sensitivity to reservoir pressure

2. On the other hand high production wells with tubing choking effect

The main tubing string of that Well is presented by 5 ½" × 3 ½" tubing.

Normally high production rate for Badra conditions is more than 1000-1100 m3/d (6300-6900 bbl/d). High rate wells are characterised by high wellhead pressures and temperatures (80°C comparing to 50 °C for low production wells).

Obtained results of FBHP measurement and nodal analysis have shown that FBHP is higher than target even if the choke is fully opened for 100%.(Pic 4)



Picture 4—High production well performance with tubing choking effect

High FBHP at current production rate is caused by friction losses in 3 ½" piece of tubing string that for particular well is 564 m (1850 ft) and placed in production liner. This is also confirmed by the fact that WHP and flowline pressures are 31 bar (450 psi) and 25 (362 psi) bar correspondingly.

This effect is not critical despite of obvious deferments because it eliminates itself as the reservoir is depleted.

The third category is wells that produce in Optimal mode.

These wells have production rate ranges from 300 to 1000 m3/d (1890 - 6290 bbl/d) and wellhead temperature variation from 60 to 75 °C and have FBHP around target values.

Appeared troubles such as gas slippage effect on low production wells and choking effect on high production wells lead to necessity of proper tubing string re-design for Badra wells, especially taking into account further reservoir pressure depletion.

Tubing re-design

The tubing string re-design for wells after workover should be based on principles of optimal flow performance at reservoir depletion conditions, well integrity, possibility of well interventions and stimulation.

Flow performance

Current tubing string 5 ½" 23 ppf × 4 ½" 15,1 ppf gives the minimum stable rate on low production wells around 250 m3/d (1570 bbl/d) at reservoir pressure around 230-300 bar (3335 - 4350 psi).

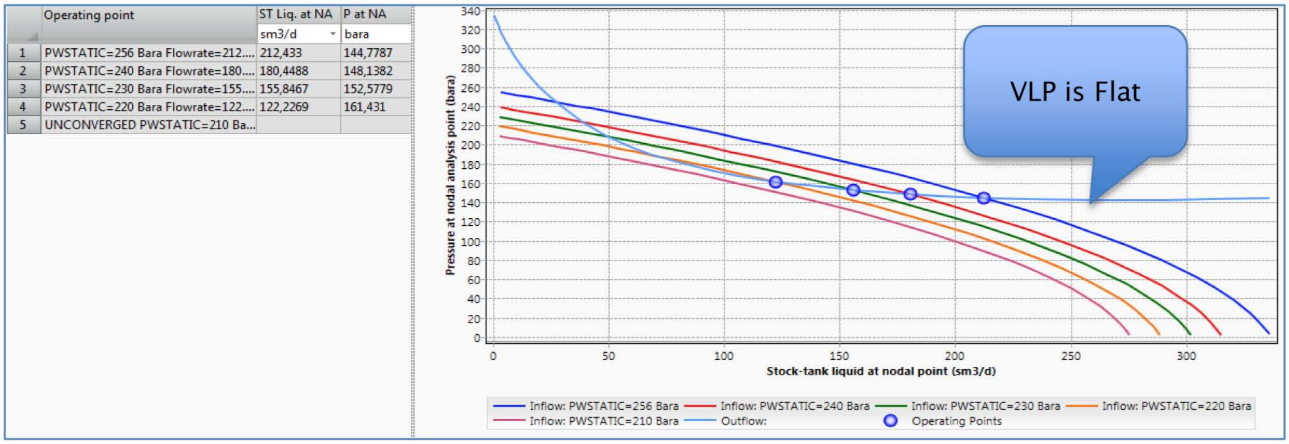
It is widely known in industry that using reduced tubing size helps to stabilise the flow and prolongate the low production well's life with lower reservoir pressure.

Using the lower diameter of tubing helps to move up the point of change from piston/churn flow to mist flow.

Several sensitivity runs were conducted to understand the optimum tubing size for low production wells with the purpose of its longer performance.

The main parameter in case with Badra field low production wells is the minimum reservoir pressure at which the well is still capable to flow.

First sensitivity run with 3 ½" tubing string was modelled. (Pic 5)

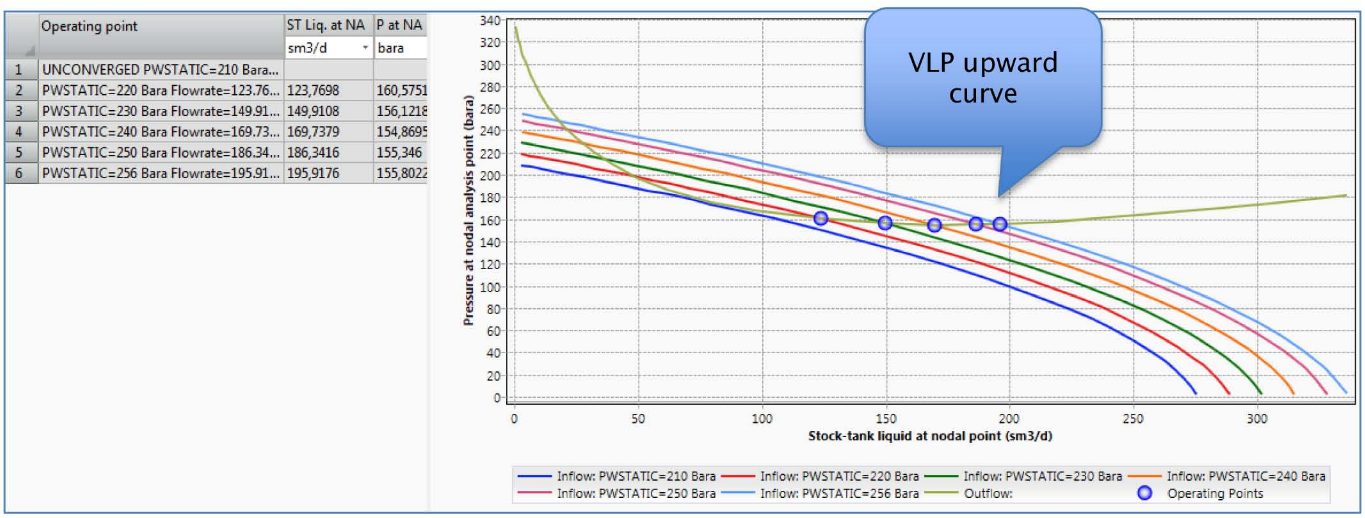


Picture 5—Tubing string sensitivity analysis with 3 ½"

It seems that using 3 ½" tubing makes the flow more stable than with 5 ½" string – VLP curve turns from downwarding to flat. However, at the same time, it is obviously not the best solution.

That is why second option was modelled – 2 7/8" tubing string.

VLP shape looks better with 2 7/8" string indicating more stable flow performance. Probably with 2 7/8" well could perform a bit longer with lower Pres than if 3 ½" were used, however it doesn't give too much increase in production lifespan. (Pic 6)



Picture 6—Tubing string sensitivity analysis with 2 7/8"

Generally speaking, changing the 5 ½" tubing string to 3 ½" or 2 7/8" could prolongate the wells life for some time until the reservoir pressure reaches 220 bar (3190 psi) comparing to 240 bar (3480 psi) with current completion.

However, it should be noted that flow performance is one of the factors that has to be assessed during tubing selection process.

Based on results obtained from set of sensitivity runs with different tubing sizes and taking into account production conditions of Badra Field, following results were obtained:

Liquid rate, m3/day	Optimal tubing size		
	5 ½”	4 ½”	3 ½”
Q min	500	300	200
Q max	2000	1600	1100

Q min indicates minimum stable flow

Q max indicates the maximum point above which friction losses starts significantly increase.

There is a good example of tubing choice correctness appeared in 2018. New well was drilled to the same reservoir. The well was not expected to have average production rate. Initial rate given by reservoir engineering department was around 500 m3/d (3150 bbl/d). In fact, production rate was quickly reduced to 200 m3/d (1260 bbl/d) within several months from the start date. However, there is no flow interruption is observed on the well with choke 45% that clearly shows effectiveness of using reduced tubing size of 3 ½". (comparing to 250 m3/d (1570 bbl/d) with 25-30% choke with 5 ½").

Flow interruption on wells completed as per older design started at 250 m3/day (1570 bbl/d).

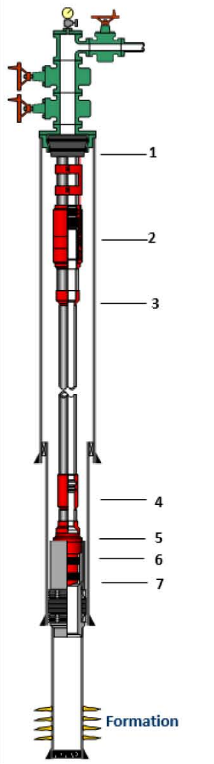
Second criteria for tubing string selection is well integrity - sustainability to expected loads and sufficient resistance to corrosive fluid environment.

Based on obtained results of flow performance calculations it was decided that the main part of tubing string should be 3 ½".

However, there are several additional factors that have to be taken into account.

- Tubing hanger and TRSCSSV are 5 ½" were selected by initial design. Thus, upper part is presented by 5 ½" tubing.
- Production liner was replaced from 5 ½" to 4 ½" with the purpose of using standard drill bit sizing and better cementing quality. Production liner equipped with PBR.
- In addition to that, Pull to release production packer was replaced with tie-back stem that is set in PBR.

Final completion design is presented on the picture below (Pic 7):



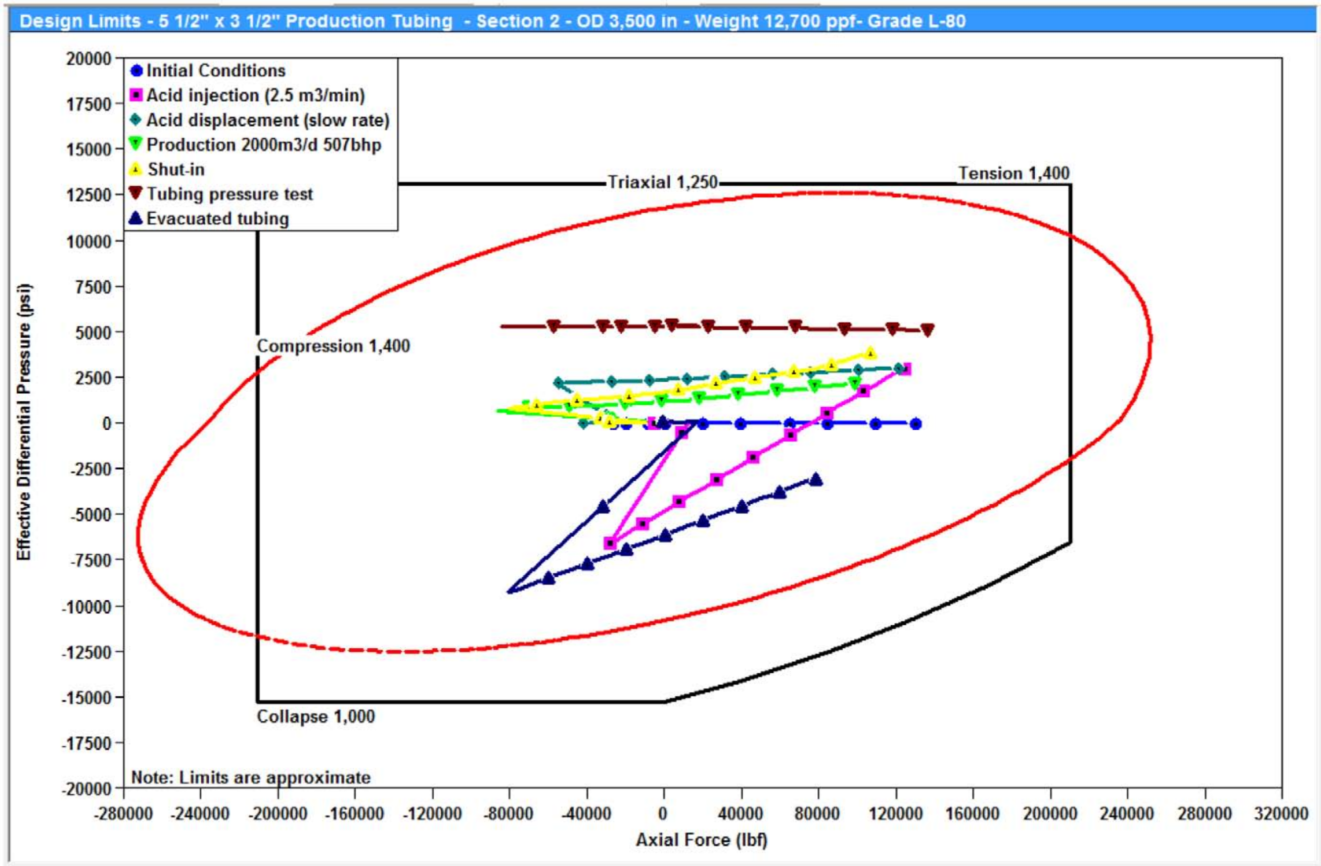
LAYOUT	No	Part No	Assy# / SN	DESCRIPTION	I.D.	O.D.	LENGTH (m)	DEPTH (m)
				ELEVATION			**9,170**	0,000
	1		TH Assy #1	**Tubing Hanger, 5-1/2" 23# Vam Top BxB**	4,782	10,875	0,520	9,170
				Pup Joint, Double pin 5-1/2" Vam Top Pin x Pin	4,670	5,500	1,835	9,690
		Pup		5-1/2" Tubing, 23 ppf VamTop Box x Pin, L80 (space out)	4,670	6,156	1,962	11,525
		Pup		5-1/2" Tubing, 23 ppf VamTop Box x Pin, L80 (space out)	4,670	6,156	1,954	13,487
		6		5-1/2" Tubing, 23 ppf VamTop Box x Pin, L80	4,670	6,156	57,409	15,441
	2		TRSV-01	Pup Joint 5-1/2" 23 ppf VamTop Box x Pin, L-80	4,670	6,156	1,952	72,850
				Flow Coupling, 6ft, 5-1/2" 23 ppf VamTop BxP, Alloy 925	**4,560**	**6,210**	1,707	74,802
				TRSV, SP, H2S, 10K, 5 1/2" 23# VamTop B x P, Alloy 925	**4,437**	**7,990**	2,620	76,509
				Flow Coupling, 6ft, 5-1/2" 23 ppf VamTop BxP, Alloy 925	**4,560**	**6,210**	1,728	79,129
				Pup Joint 5-1/2" 23 ppf VamTop Box x Pin, L-80	4,670	6,156	0,936	80,857
		3		5-1/2" Tubing, 23 ppf VamTop Box x Pin, L80	4,670	6,156	28,714	81,793
	3			Crossover 5-1/2" VamTop Box x 3-1/2" VamTop Pin	2,720	6,211	0,365	110,507
		451		3-1/2" 12.7 ppf VamTop Box x Pin, L-80	2,707	4,043	4199,249	110,872
	4			**LANDING NIPPLE 2.56" GF Top No-Go 3-1/2" 12.7ppf VAM TOP**	**2,562**	**4,043**	0,425	4310,121
		1		3-1/2" 12.7 ppf VamTop Box x Pin, L-80	2,707	4,043	9,332	4310,546
	5			Crossover 3 1/2" 12.7 ppf L80 VamTop Box x 4 1/2" 15.1 ppf VamTop	2,707	4,545	0,375	4319,878
	6	**GOT**		**Tieback Stem, 4 1/2" 15,1# Vam Top box up with 4 Seal-sets**	**3,815**	**5,551**	6,510	4320,253
				END OF TUBING				**4326,763**
	7	**GOT**		**4-1/2" PBR**	**4,980**	**5,551**	5,980	4321,283
				Bottom of PBR				**4327,263**

Picture 7—Final completion design for low rate wells

There are two aspects that has to be taken into account:

- Top section of tubing is 5 ½" 23 ppf and 5 1/2" TRScSSV are used as per original design. Replacing these elements requires replacing tubing hanger as well. Short length of 5 1/2" section does not create any negative impact on flow performance or TSA.
- 4 ½" tie back stem is also used as per original design to fit the PBR installed on 4 ½" production liner.

Tubing Stress Analysis has been performed to assess the applicability of the concept to expected loads. (Pic 8)



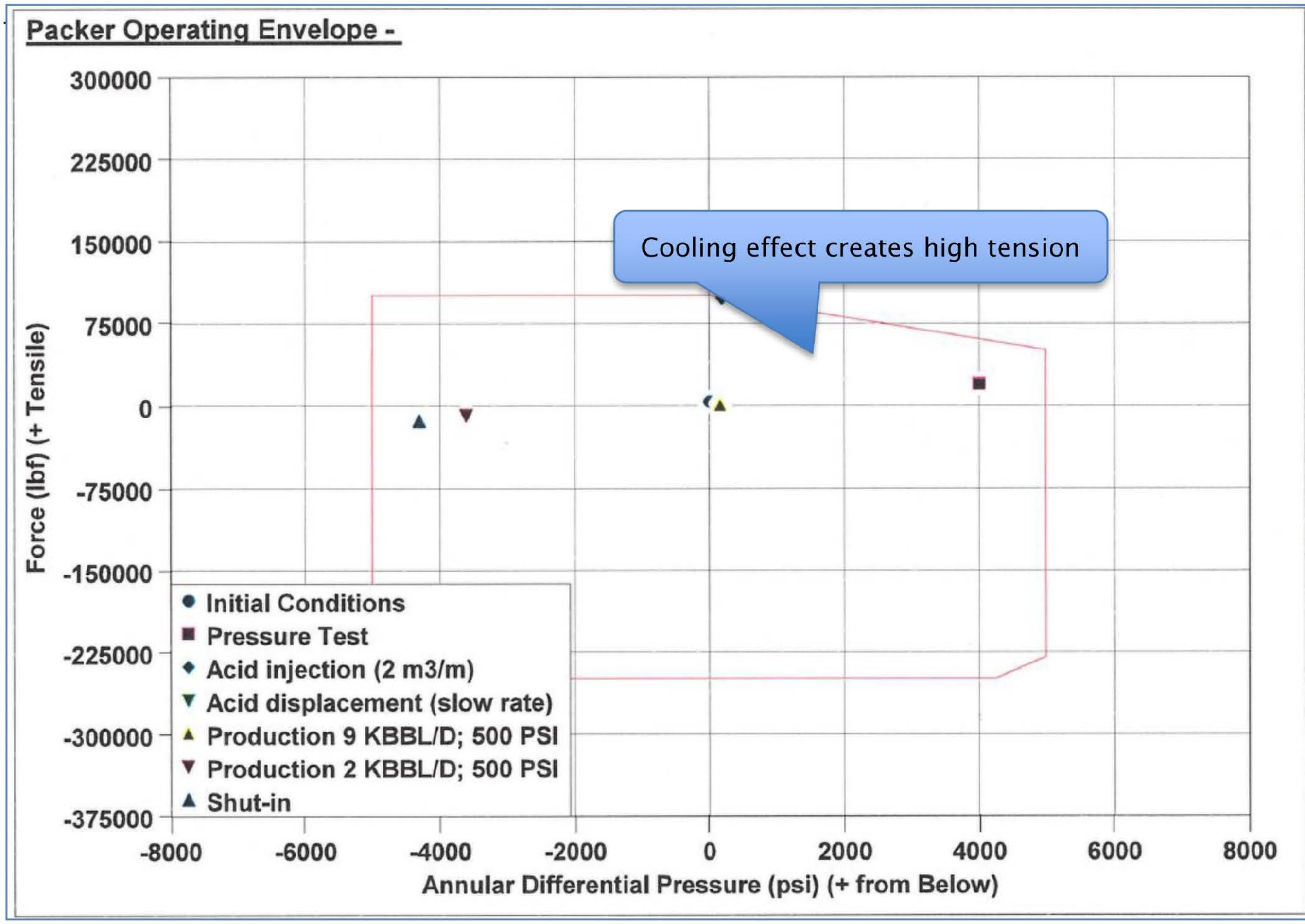
Picture 8—Tubing stress analysis results of 3 ½" string

New completion design assumes replacing of pull to release production packer with Tie-back stem. Whereas, for wells where no PBR is installed and pull to release production packers were used, it is proposed to change the packer types to CUT to release rated for minimum 517 bar (7500 psi) differential pressure.

Picture below shows packer operating envelope of one of the first old designed well with production packer installed.

Packer is rated to 345 bar (5000 psi), but it seems that it is not fully applicable for such conditions. This might be one of the reasons for A-ann pressure issues. (Pic 9)

To eliminate this effect it is proposed to install the travel joint above production packer for such wells in case if there will be no possibility to purchase 517 bar (7500 psi) rated production packer.



Picture 9—Packer operating envelope

Additional calculations were performed to find out the maximum overpull that can be applied to 3 ½" tubing and 2 7/8" tubing string. Results are 27 (54000 lbs) and 20 tons (40000 lbs) correspondingly.

Axial loads and corrosion resistance

It was previously mentioned that standard approaches for completion design not always could be applied for Badra conditions.

Clear example can be shown when axial loads are calculated.

Average depth of Iraqi wells on south is around 3000 m TVD (9840 ft), whereas Badra wells have depth about 4500 m TVD (14760 ft).

Two tubing types are considered for implementation: L-80 3 ½" 12.7 ppf and L-80 2 7/8" 10.5 ppf. Pipe body yield strength was calculated as per API 5C4.(Table 1)

General corrosion on internal side is assumed.

Values for pipe body yield strength were calculated by means of Formula 30:

$$P_y = 0.7854(D^2 - d^2)Y_p \quad (30)$$

Where:

P_y = pipe body yield strength in pounds rounded to the nearest 1000.
Y_p = specified minimum yield strength for pipe, pounds per square inch.
D = specified outside diameter, inches.
d = specified inside diameter, inches.

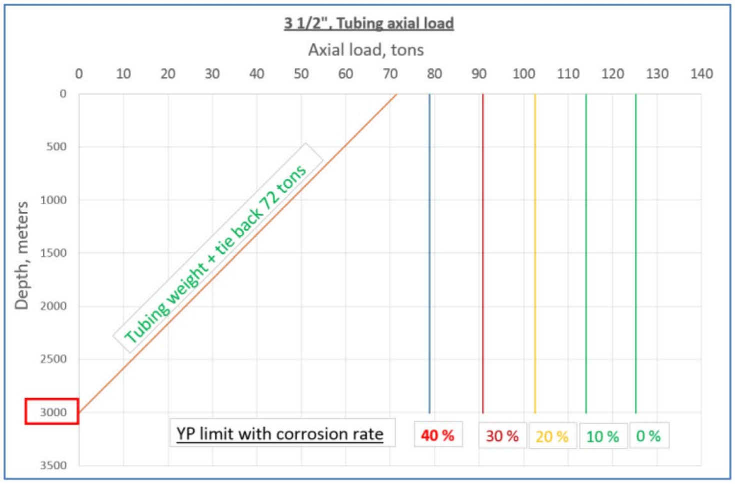
Formula 30 of API 5C4: Calculation of Pipe Body Yield Strength

Table 1—API Yield strength calculation

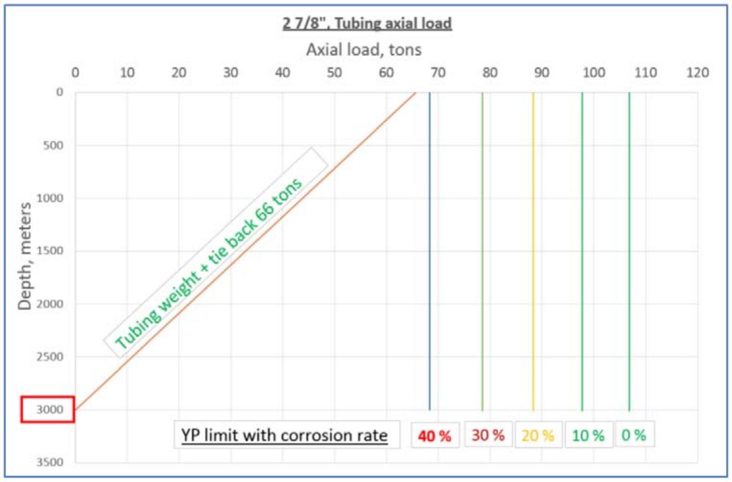
2 7/8 Design Factor 1.4						
Corrosion rate, %	0%	0%, temp derated	10%	20%	30%	40%
Yield strength, lbs	251	236	216	195	173	151

3 1/2 Design Factor 1.4						
Corrosion rate, %	0%	0%, temp derated	10%	20%	30%	40%
Yield strength, lbs	295	276	251	226	200	174

Tubing weight (buoyant) was calculated for two cases: 3000m (9840 ft) and 4500m (14760 ft). (Pic 10,11,12,13)



Picture 10—Tubing axial load 3 ½", 3000 m



Picture 11—Tubing axial load 2 7/8", 3000 m

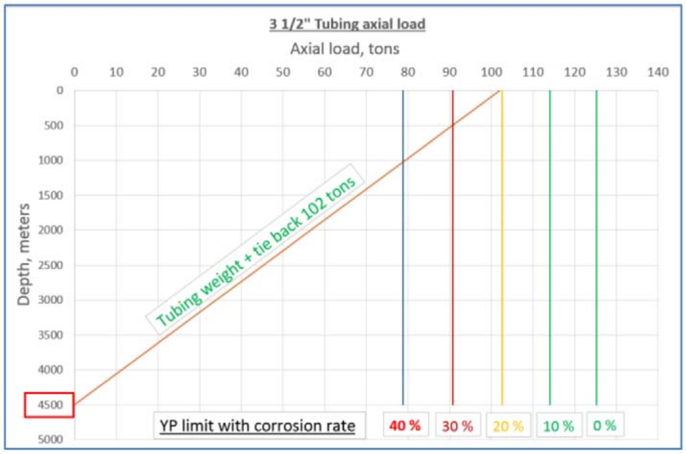
There is no too much difference between using 3 ½" and 2 7/8" tubing for 3000 m (9840 ft) wells. For such depth, both tubing types can sustain up to 40% of metal loss (general corrosion assumed).

However, at depth of 4500 m (14760 ft) TVD, 2 7/8" tubing can sustain only 10% of metal loss.

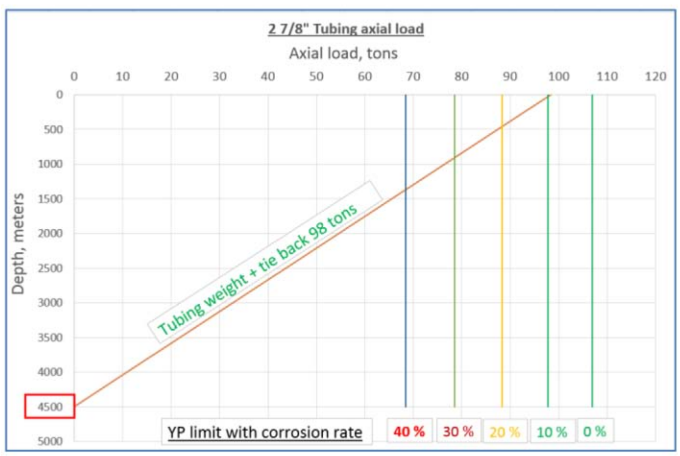
At the same time 3 ½" tubing string can last until general corrosion reaches 20%.

Overall tendency states that deeper wells at some point require stronger and larger diameter pipe.

It should be noted that no production packers or any causes of overpull were considered.



Picture 12—Tubing axial load 3 ½", 4500 m



Picture 13—Tubing axial load 2 7/8", 4500 m

Based on results of these calculations and calculations in Wellcat 3 ½" tubing string it taken as the most suitable.

L-80 steel grade selection

Material selection overview for production tubing has been performed in accordance with NACE MR 0175 / ISO 15156.

Basic approach dictates selection of High Alloy materials that have strong resistance to CO2/H2S corrosion such as Alloy 28 or SM 2535.This approach mainly based on H2S /CO2 partial pressure and in-situ PH.

On the other hand there is a wide practice of using L-80 carbon steel for production tubing in H2S environment, which is also stated in NACE MR 0175.

Badra team recommends keep using L-80 under circumstances of absence of high Water cut and switches over to gas on production wells. If water breakthrough occurs or well switches to gas, corrosion rate will be much more intensive.

Additional arguments to support L-80 for Badra conditions:

- Several buffering factors for corrosion exist on Badra field. One of the main is the presence of asphaltenes (1.25-8.91 %) that contribute "natural" corrosion inhibition.
- L-80 cost. Performed market research has shown that high alloy steels are 10 times more expensive than L-80 on average in the region.
- Well interventions. Many well interventions are performed on Badra oilfield. These are Coiled tubing during Acidizing, PLT logs and standard pressure/temperature measurements, setting and removing the plug during tubing pressure testing. Every intervention creates the risk of localized corrosion development due to scratches created while interventions.
- Tubing stress analysis. 3 ½" 12,7 ppf L-80 material has sufficient strength to sustain expected loads with 20% of corrosion in Badra conditions (DF 1.4)
- There is no guarantee that using High Alloy steels exclude localized pitting corrosion due to manufacturing imperfections or well interventions, thus one little hole in the tubing reduces the effect of High alloy string to zero.

Despite the presence of number of arguments, the main driver of L-80 selection is its economical attractiveness. It is more practical to perform workovers a bit more frequent rather buying tubing grade 10 times higher price.

Similar solutions have already been implemented in the industry in the past (**SPE 27604 Downhole material selection for Clyde Production Wells**).

Annulus pressures monitoring

4 out of 9 wells initially completed by old design with pull to release production packers installed, have constantly rising A-annulus pressure.

However, it should be noted that intensity of A-ann pressure rising is different for each well. There are several wells where A-ann is bled off on repetitive basis. Other wells observe this problem from time to time, usually after field long shut downs.

New wells completion concept included replacing of 345 bar (5000 psi) rated Pull to release production packer with with tie-back stem (and PBR) that rated for 860 bar (12500 psi) differential pressure. Situation had improved as a result.

Only one well from 10 wells with new design has rising A-ann pressure.

Thus, there is a clear evidence of improving the situation by using Tie-back stem and PBR instead of pull to release production packers.

Possibility to perform Acidizing treatment

HCL acidizing is used on Badra oilfield as the main stimulation treatment method. Acidizing job consists on three main steps:

- □ Tubing pickling and wellbore washing
- □ Main Acid job
- □ Well clean-up with nitrogen

Pickling job on Badra production wells is performed with running the CT to the bottom of the tubing and circulating the HCL 10% to the surface. Volumes and pump rates are selected individually for each well.

For proper implementation of acid wash, the CT is run to the perforation interval and 15% HCL is spot across the perfs. Once the acid pad is placed across the perfs, it is pushed to the perfs and soaking time (30 min) is spent to dissolve the residues in perf tunnels and near wellbore zone.

The Injectivity test is performed once the soaking time is finished. It is required to understand the reservoir-wellbore connectivity. Successful acidizing is impossible without the proper cleaning of perforation tunnels and near wellbore zone.

Based on an industry experience and taking into account Badra geological conditions, High Volume Matrix Treatment was selected as the main Acidizing concept.

Badra formations mostly consist of limestone with few small interlayers of dolomite, thus 15% HCL is selected as a Base acid.

The Main Acid Pumping phase starts after the pickling job and acid washing has been finished, Well-reservoir connectivity was established and CT was pulled out from the hole.

Based on the previous experience it was found that optimal Acidizing design includes: 5 m3/m (9.6 bbl/ft) of 15% HCL is injected at a target pump rate of 2,4-2.6 m3/min (15 bbl/min).

Total volume injected during the acidizing treatment usually around 400 m3 (2516 bbl). Therefore, injection rate is crucial parameter for successful acidizing on Badra Oilfield.

Relatively low HCL concentration (15% instead of 28%), high volume 5 m3/m (9,6 bbl/ft) and high pump rate are designed to create long wormhole channels. Whereas short and wide channels are usually created with high HCL concentration (28%) and small injection rates and volumes.

Well depth up to 4500 m TVD (14760 ft), gross formation thickness up to 370 m (1214 ft), Net perforation intervals of 80 m (260 ft) and laminated formation structure are the main factors for choosing the Bullheading (with diverters) injection method.

This factors was also considered while selection of the optimum tubing size. Performed calculations have shown following results:

- 5 ½" tubing with following 4 ½" production liner allows injection rate around 20 bbl/min (3.18 m3/min)
- 3 ½" tubing string can transmit up to 15 bbl/min (2,4 m3/min). (Target injection rate by design is 15 bbl/min, historical field experience is 12-15 bbl/min).
- 2 7/8" significantly restricts acid bullheading to 8.5 bbl/min (1,35 m3/min)

The smaller the tubing size the higher the friction losses during injection. Too small tubing size creates high wellhead injection pressures that for Badra conditions are limited by 275 bar (4000 psi).

All of this eventually leads to reduction of acidizing efficiency.

Therefore, 3 ½" tubing string is the most suitable tubing size for current conditions taking into account Acidizing operations design.

One of the methods of selective acidizing was also implemented on Badra field – CoilFlate. CoilFlate for selective acidizing includes mechanical isolation of treated formation with inflatable packers. Maximum OD of released packer is 2.25".

2 7/8" tubing string has Drift ID 2.057 in, thus 3 ½" is the only applicable tubing size if this option is planned to be used in future.

Well interventions

Every well design should assume presence or absence of intervention operations in the future.

Most of the tasks such as FBHP/FBHT measurement, injection profile monitoring nowadays can be solved by installation of Pressure downhole gauges and fiberoptic cables for temperature monitoring.

However, these options are not always applicable in harsh environments like Barda oilfeild.

Several types of well interventions must be performed on Badra wells in the future:

- PLT

PLT tool size that used in Badra Oilfield is 1.688". Landing Nipple ID that installed on 3 ½" tubing is 2,562 in. Therefore, no any difficulties are expected.

- Coiled tubing intervention for acidizing or removing of water from the bottom

Coiled tubing OD that is used on the field is 1.75" that also can pass through the Landing Nipple.

There are several intervention types that are not going to be implemented on the field by now, but should be considered as possible options:

- Re-perforation or additional perforation

Re-perforation or additional perforations were not planned as per basic completion design.

However, there was one successive case of additional perforation on Badra field that was done with wireline conveyed perforation gun and showed real increase in production rate of the well.

WL conveyed guns applicability was assessed prior to make a decision about tubing size replacement. The main aim was to estimate whether it would be enough power to bypass the damaged zone on wells with 5 ½" Production liner and 3 ½" tubing string.

Tubular(s)

Casing #	Outer Diameter (in)	Weight (lbm/ft)	Grade	Inner Diameter (in)	Tubing Position	Stand-off	Annulus Material	Annulus Density (ppg)	Csg Str Remain (%)
1	5.5	23.00	L80	4.67	Centralized		Cement	15.86	98/98/98/95

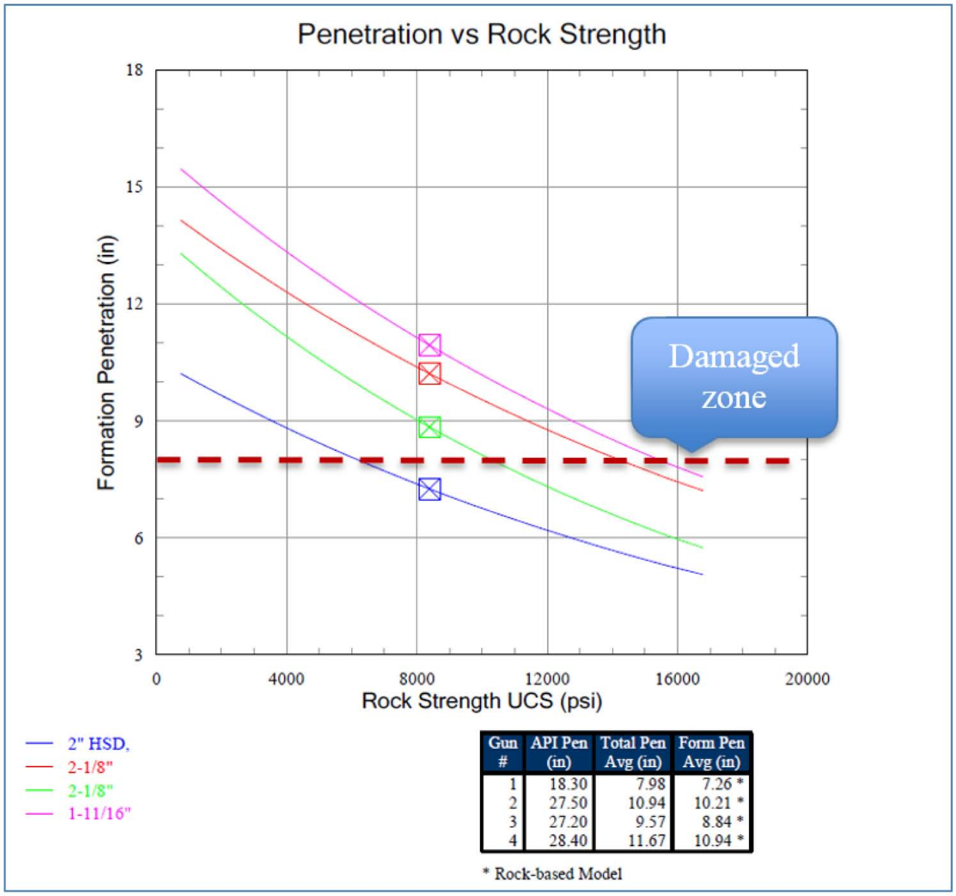
Rock is classified as high strength with following parameters:

Formation

Rock Type:	Limestone		Rock Strength (UCS):	8385	psi
Porosity:	10.0	%	Vertical Stress:	14764	psi
Bulk Density:	2.44	g/cm3	Pore Pressure:	4500	psi
Formation Fluid:	Gas		Wellbore Damage:	8	in

Several perforation gun types were assessed with the purpose of understanding the possibility to pass through the minimum restriction of 2.56", perform sufficient penetration to bypass damaged zone and be successfully retrieved to surface.

At least three types of perforation guns can be used to perforate 5 ½" production liner and be conveyed n WL through proposed 3 ½" tubing string. (Pic 14)



Picture 14—Perforation guns performance

That is why, selection of 3 ½" tubing size allows using 2 1/8" WL conveyed perforation guns, whereas 2 7/8" allows only 1 11/16" guns.

- Installation of water shut-off plugs

The PosiSet plug-back was run into one of production wells for water producing interval isolation. MPSU-BA Plug has OD of 1.71 in.

Both 3 ½" and 2 7/8" tubing allow using this type of plug. However, larger size MPSU-CA plug has OD of 2.215" that can be run only through 3 ½".

- Cable conveyed ESP

Recently developed Cable conveyed ESP provide the possibility to use ESP without making a full well workover with pulling out of hole tubing string.

The principle is using specially enforced EPS cable as a conveying element. That cable comes out from the top of Xmass tree similar to how it works with coiled tubing.

Whenever ESP has to be changed, no tubing retrieving and replacement is required.

Minimum size of tubing required for using this technology is 3 ½".

Conclusion

Number of factors affecting completion design have been assessed before making a decision about changing the tubing size and completion components on production wells of Badra Oilfield.

The main outcome is that for such conditions as on Badra field, vertical wells 4500 m (14760 ft) depth, selection of 3 ½" tubing string is a right choice for production rates 200-1100 m3/d (1260-6900 bbl/d) As it was shown by flow performance analysis, tubing stress analysis 3 ½" tubing provides stable flow regime from 200 to 1100 m3/day (1260-6900 bbl/d) up to the minimum reservoir pressure of 240 bar (3500 psi) and has sufficient resistance to all expected loads up to 20% of metal loss.

It is also does not create any restrictions for stimulation treatments or any well interventions including perforation.

There are at least 3 perforation guns with sufficient penetration performance that can be conveyed on wireline through 3 ½" tubing.

Using of 3 ½" tubing with tieback and PBR instead of 5 ½" × 3 ½" string with pull to release production packer makes purchasing of completion components cheaper and increases the well sustainability to expected loads.

Moreover, reduced axial load allows using the tubing string for the longer period comparing to previous design by increasing corrosion allowance.